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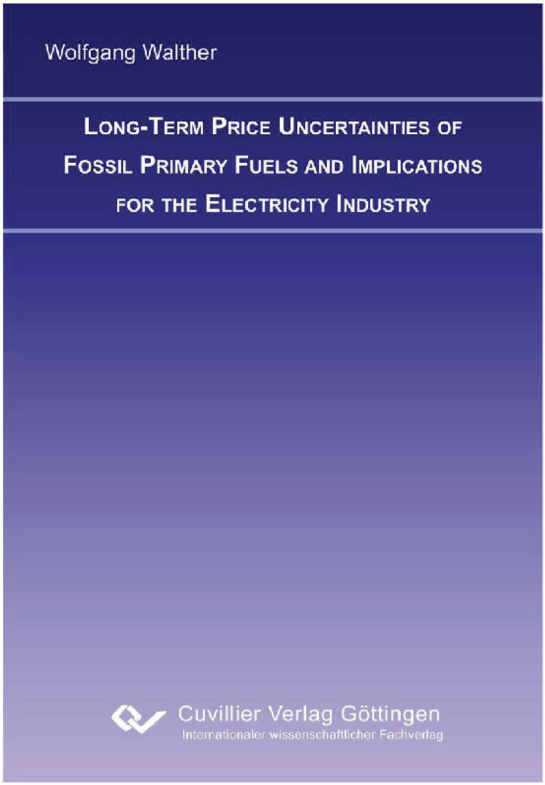
Long-term Price Uncertainties of Fossil Primary Fuels and Implications for the Electricity Industry



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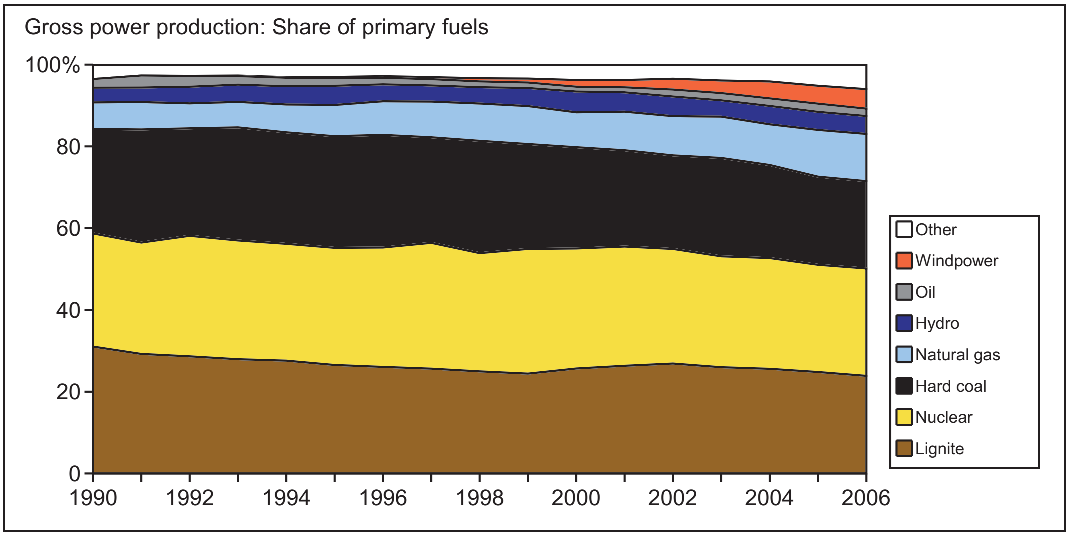
2 Capacity investments in the German electricity industry

Investments in generation capacity are currently an important issue for German (and European) electricity companies. This chapter briefly explains why new generation capacity is urgently needed at the moment and how uncertain fuel prices and CO_2 emission costs increase the risks related to these decisions. Using both the historical development and probable future trends, it is discussed in the first section why fossil fuels will continue to play such an important role in power generation and why this thesis is relevant for corporate planners in utility companies. In the second section, this chapter shows how market liberalization further complicates the situation.

Since the following discussion of the German electricity industry is primarily dedicated to the relevance of fossil fuel prices for investment decisions, it focuses very much on generation. Other steps of the value chain, like transmission and distribution, will not be considered in detail. Still, it should be kept in mind that the future portfolio of power plants is likely to impact investment decisions at least for the transmission grid, too. Few large-scale power plants fired by lignite, hard-coal or nuclear fuels require a different grid structure than a portfolio consisting of small distributed generation facilities (cf. e.g. Weber and Vogel 2005).

2.1 Status quo

Power generation in Germany is primarily based on three energy sources: lignite, nuclear fuels and hard coal. Fig. 2-1 shows the development of fuel shares in gross production since 1990.



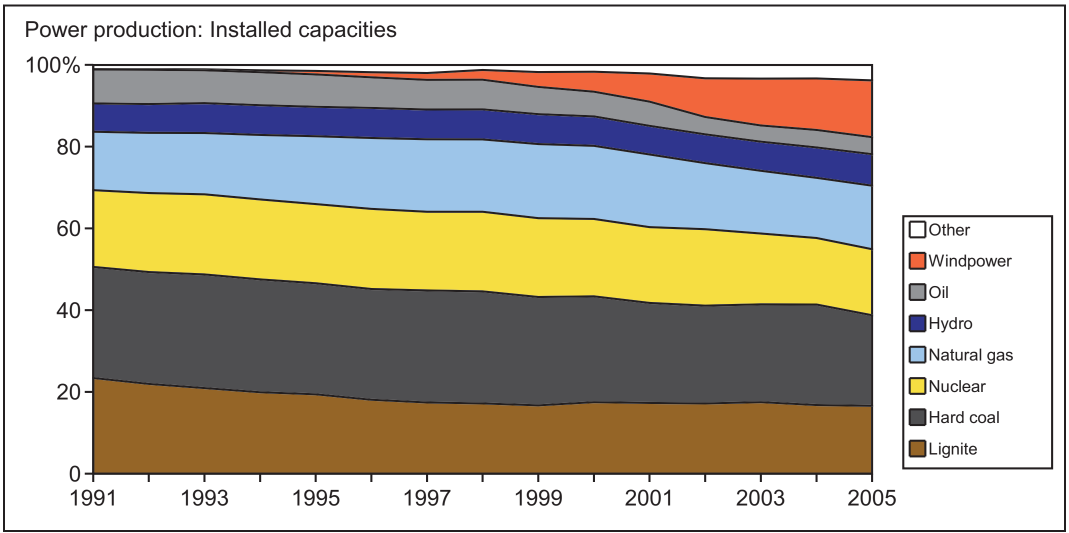
Source: Own representation based on BMWI (2007)

Fig. 2-1: Primary fuel shares in German gross power generation 1990 – 2006

In 2006, lignite is still holding the largest share with 24 percent although its portion has been decreasing from over 31 percent in 1990. This is partly due to the high specific CO_2 emissions of this technology and probably also to the change in the industrial landscape and electricity demand in former Eastern Germany resulting in a shut-down of lignite-fired plants there.

The second-largest share is currently being held by nuclear generation. The future development here is unclear: In 2000, a phase-out of nuclear generation had been agreed upon, creating an additional demand for generation capacity in the magnitude of 20 GW until 2020 (cf. e.g. Pfaffenberger and Hille 2004, p. 3.38f.). However, the revitalization of nuclear generation is currently being debated to reach the CO_2 emission targets.

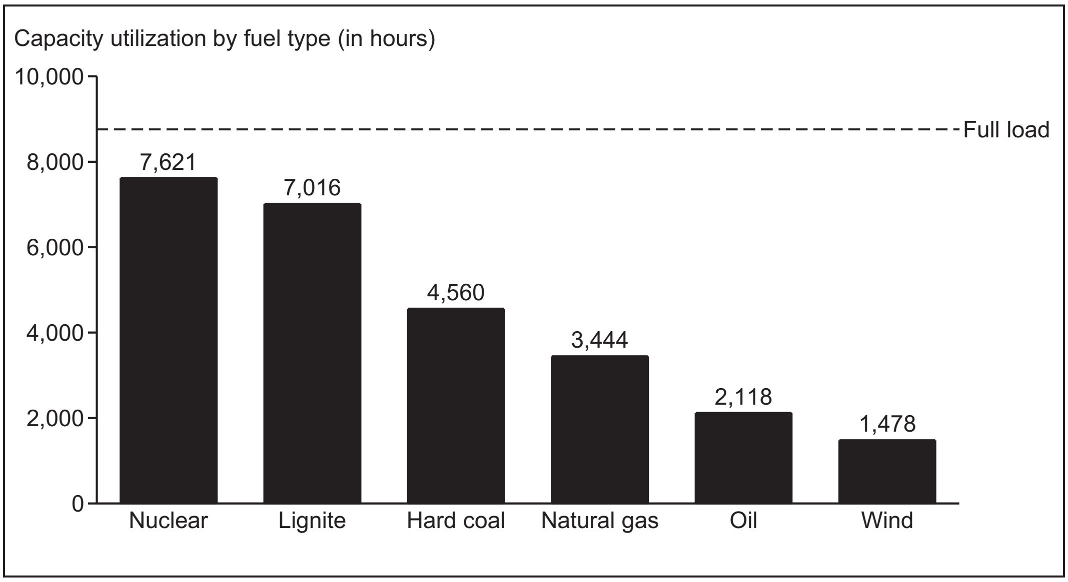
The development of installed capacities is similar, but not identical to the shares in gross production (cf. Fig. 2-2). Most obviously, the share of hard coal and natural gas is higher in installed capacity than in gross production due to the different load hours of power plant types (cf. Fig. 2-3). These technologies are primarily deployed in middle load and peak load generation, resulting in lower annual capacity utilization than for lignite and nuclear plants.



Source: Own representation based on BMWI (2007)

Fig. 2-2: Share of primary fuels in German installed capacity 1991 – 2005

Wind power capacities have experienced significant additions since the early 1990s (cf. e.g. Pfaffenberger and Hille 2004, p. 3.40f.). Largely, this has been driven by significant public subsidies to promote the usage of environmental-friendly renewable energy sources. Due to the wind-dependent and thus fluctuating production, wind power cannot be used to substitute the installed capacity of conventional thermal plants on a one-to-one basis. This is also reflected in the low capacity utilization of wind power plants as shown in Fig. 2-3. In addition, further onshore locations for wind power generation are limited since most good locations are being used already. Future installations are thus likely to be offshore facilities, requiring higher investments both in generation and in transmission networks. For the same reasons, a significant increase in hydro power generation is unlikely for Germany.



Source: Own representation based on BMWI (2007)

Fig. 2-3: Capacity utilization of German power plants in 2005

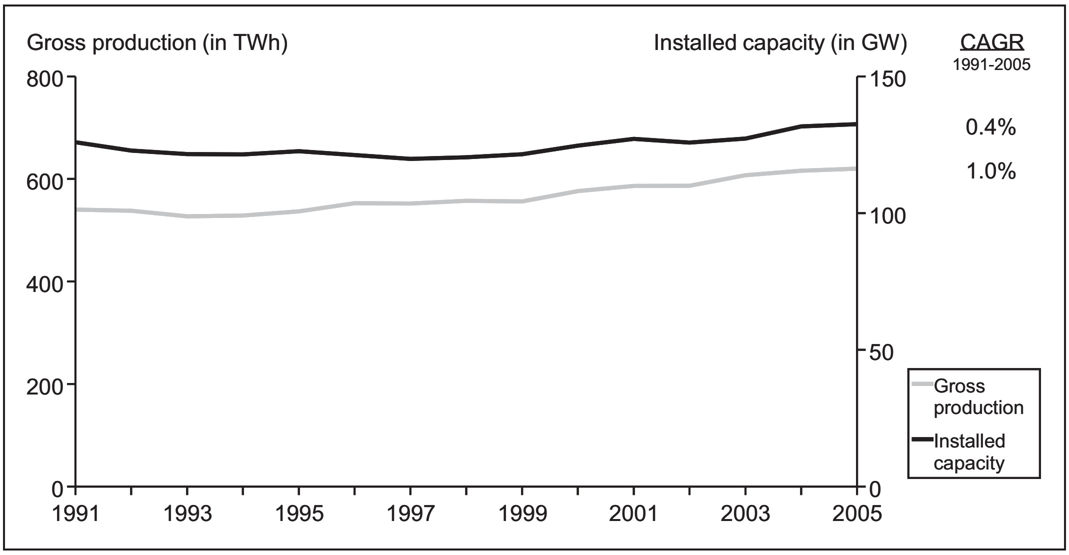
In summary, the mix of generation technologies in Germany is due to a wide range of key drivers (cf. e.g. Pfaffenberger 2002, Pfaffenberger and Hille 2004, Weber and Swider 2004, Pfaffenberger 2005 and Weber 2005a, 2005b):

- Fuel costs
- Diversification of fuel types to ensure the security of supply, especially after the oil crises in the 1970s (also cf. subsection 5.2.5)
- Environmental impacts, e.g. CO_2 emissions or ultimate waste disposal for nuclear fuels

- Technical specifications, e.g. ramp-up times, partial load efficiencies, minimum up- and down-times that are relevant for the possible modes of operation, i.e. the deployment for base or peak load generation[4].

Also for future investments, these four factors will continue to play an important role. The focus of this thesis is primarily on the theoretical discussion and model development related to the first point, i.e. fuel prices. Of course, this first point is significantly impacted by the second and third point, i.e. security of supply and environmental impact. The last topic, technical specifications, will be considered in the model applied in chapter 8 with regard to investment in generation capacities.

The levels of gross production and thus also of installed capacity have been rather constant over the last 15 years, as depicted in Fig. 2-4.



Source: Own representation based on BMWI (2007)
Note: CAGR = Compound Annual Growth Rate

Fig. 2-4: German gross production and installed capacity 1991 – 2005

Since many power plants are reaching the end of their technical lifetime[5] within the next years, substantial capacity investments are required to maintain the se-

[4] Lignite and nuclear plants are used for base load generation due to two reasons: First, their fuel costs are comparatively low, making the technologies ideal for 24/7 deployment. Second, they have long ramp-up times in the magnitude of several hours or even days, prohibiting the use in peak load generation. By contrast, gas-fired turbines have start-up times of a few minutes but high fuel costs. Therefore, they are used in peak load generation only, i.e. possibly only a few hours per year.

[5] Pfaffenberger and Hille (2004) assume a maximum lifespan of 40 to 45 years for power plants. They also allude to the fact that lifespan is not necessarily the limiting factor since revamping can significantly prolong the technical lifespan. However, old plants are not likely to reach the efficiency and thus the low operating costs of newly constructed plants.

curity of supply in Germany. Pfaffenberger and Hille (2004) calculated a total required investment of 40 to 50 GW until 2020. This includes the 20 GW needed from exiting nuclear-fueled generation.

Despite the efforts to promote renewable fuels in Germany and Europe, the major share of the replacement capacities is likely to be covered by fossil-fueled plants. Due to their fluctuating availability, most renewable energy sources cannot be used to provide 24/7 base load generation capacities. Significant electricity imports from other European countries are not an option either as the tight supply situation is the same all over Europe (cf. Weber and Swider 2004). Assuming that the nuclear phase-out will not be revised, fossil fuels remain the only large-scale technology available over the next decades until new technologies like thermonuclear fusion may become available. For strategic planners in utility companies, the key question is now to decide on the type of fossil fuels for new investments: "*Fuel prices affect the operation costs of the plants, and thus both prices and optimal capacities in a long-term equilibrium depend on observed or expected fuel prices*" (Weber 2005b, p. 242).

2.2 Impact of market liberalization and fuel price uncertainties on investment decisions

The liberalization of the German electricity industry started in 1998 when the law regulating public energy supply ("*Energiewirtschaftsgesetz*", EnWG) was amended[6]. The general objectives of the law include security of supply, cost effectiveness and environmental friendliness, sometimes also referred to as the *magic triangle* of energy policy. Later, also reasonable pricing and consumer-friendliness have been added to the objectives. Regarding power generation, cost effectiveness is to be realized by the breakup of regional monopolies, increased competition between utility companies and power plants, resulting in the reduction of monopoly rents. Also, an electricity exchange has been introduced, providing the possibility to trade spot and future contracts.

In a first phase, the liberalization led to a fierce competition on retail prices and saw both the entrance of new players and mergers of existing companies[7]. Since about 2002, the market has entered into a second phase in which market consolidation took place. In 2004, about 80 percent of the German generation ca-

[6] It would exceed the scope of this thesis by far to discuss the detailed setup of utility deregulation and liberalization in Germany. Cf. e.g. Schulten (2004) for an overview and Schmitt (2007) for a discussion of future developments.

[7] In 2000, VIAG and VEBA merged to form E.ON. In 2002, RWE merged with VEW. The fusion of VEAG, BEWAG, HEW and LAUBAG led to the creation of Vattenfall Europe in 2002 (cf. Schulten 2004).

pacities were owned by one of the large four utility companies EnBW, E.ON, RWE and Vattenfall Europe (cf. Schulten 2004).

In summary, the liberalization created a number of strategic challenges for all utility companies. Customers are not assigned to a specific generation company any longer but can freely choose their supplier. Thus, utilities have to make efforts to gain and retain customers both on the wholesale and retail level. Their demand volume is no longer given within a certain range but fully depends on each company's ability to sell the production on the retail or wholesale markets, be it via long-term contracts, OTC contracts or at the energy exchange. Retail competition is complicated by the fact that electricity as a commodity offers little potential for differentiation. Also, due to the compulsory regional and economical separation of their transmission and distribution networks, known as *unbundling*, electric power companies are no longer allowed to cross-subsidize their operational divisions along the value chain. Power plants are thus increasingly required to operate as autonomous profit centers, valuating the produced electricity according to the mark-to-market principle, i.e. based on the corresponding spot prices (cf. e.g. Weber 2005b).

Regarding power plant investment decisions, the impacts are significant, too. Before the liberalization, utility planners could rely on quite stable demand patterns with minor stochastic fluctuations. Regarding prices, pre-liberalization utilities were able to pass on all their costs to their customers who were not allowed to switch suppliers. Consequently, also risks in primary fuel costs could be passed on to the customers. This provided little incentive for cost-optimal generation portfolios and deployment decisions. Now, liberalization has eliminated the guarantee of cost-covering prices in generation. Utility companies are confronted with uncertainties on multiple dimensions relevant for investment decisions: demand volume, attainable electricity prices and primary fuel costs, just to name the most important ones. In addition, there are several technical peculiarities connected to power generation that further complicate the investment decision. Leaving aside some pumped-storage power stations, there is no possibility for large-scale storage of electricity. Production and demand have to occur simultaneously. Reserve capacities are required to balance demand spikes.

The economic risk connected to power plant investments is particularly relevant due to the absolute size and lumpiness of investments. A hard coal-fired plant with an installed net capacity of 750 MW requires an investment of about €800M, a lignite-fired plant with 750 MW net capacity even around €1B. A 150 MW gas turbine can be built for around €35M but will cause significantly higher fuel costs (cf. Weber 2005b, p. 263). For a decision to invest in generation capacities in a liberalized market, the investor must be sure to realize his imputed interest rate over the entire lifespan of the plant, i.e. over a period of up to 40 years. Thus, expected electricity prices must be sufficiently high to cover the full investment costs. Also, marginal costs of the new plant must not exceed the marginal costs of existing plants. Otherwise the new plant cannot be operated profitably (cf. Pfaffenberger and Hille 2004, p. 9.6f.).

The importance of marginal costs is due to a specific pricing mechanism of the electricity wholesale market called *peak load pricing* (cf. e.g. Boiteux 1960, Pfaffenberger and Hille 2004, pp. 3.19 - 3.24, and Weber 2005b, pp. 32ff. and 229ff.). Peak load pricing refers to the fact that the wholesale electricity price is set by the production costs of the marginal producer. This means that the wholesale price equals the marginal costs of the last, i.e. most expensive, plant required to cover the current demand for electricity (cf. Weber 2005a). Key driver for the variable share of the marginal costs are primary fuels prices and other costs related to fuels, e.g. CO_2 emission or abatement costs. The unfavorable development of the price for a specific fossil fuel, e.g. natural gas, can mean that gas-fired plants are not able to regain their investment costs: "*The major market risk for any power plant investment in the longer run is that fuel prices (and/ or technology) develop in a way that a once-built power plant is not competitive any more. Thereby two cases have to be distinguished: one possibility is that the technology is no longer part of the efficiency frontier at all. Another is that the range of efficient operation hours (and consequently the optimally installed capacity) of the technology decreases. In both cases, the capacities already installed can still be operated, but they have to accept a reduced operation margin*" (Weber 2005b, pp. 245 - 246).

Also the volatility of fuel prices impacts the decision for or against a certain fuel technology. The higher the volatility of e.g. natural gas prices, the higher is the risk that capital-intensive technologies like hard coal-fired plants become economically inefficient (cf. Weber 2005b). If gas prices fall low enough, gas-fired plants can be operated profitably also for medium or even base load generation, squeezing out coal plants due to the lower investment costs of gas-fired plants. Therefore not only the average or median development of fuel prices must be considered but also their volatility.